minimum tax, marginal percentage depletion deductions are worthless--in fact, extra deductions would raise the taxpayer's total liability. Thus, the alternative tax changes a $50 tax saving to a $20 liability. Only taxpayers with very large amounts of tax-preferred income will be subject to the alternative tax.

The corporate add-on minimum tax imposes a 15 percent levy on the excess of percentage depletion over the basis of the property. When the basis has been reduced to zero, the minimum tax imposes an additional tax of $21.90 (per $100 of depletion), thereby reducing the tax benefit of depletion from $46.00 to $24.10, a reduction of 48 percent.[4]

REDUCED WINDFALL PROFIT TAX RATES FOR INDEPENDENT PRODUCERS

The Crude Oil Windfall Profit Tax Act of 1980 established a federal excise tax on oil production based on an estimate of the windfall profit received by producers as a result of oil price decontrol. The act basically established three categories of oil and set different tax rates for each class. The three oil "tiers" are defined as follows:

Tier One. All oil except that oil classified as Tier Two or Tier Three.

Tier Two. Stripper oil (that is, oil produced from wells with less than 10 barrels per day of production) and oil produced from the Naval Petroleum Reserve.

Tier Three. Newly discovered oil (production from properties developed after 1978), heavy oil, and incremental tertiary oil.

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4 The reduction in the tax benefit from depletion resulting from the add-on minimum tax is greater than simply the rate (15 percent) times the preference amount (for example, $100). This effect is a result of the fact that a firm's regular tax liability is deducted from the minimum taxable income. For example, the $100 preference gives rise to a tax saving of $46 in regular tax and a direct minimum tax of $15, for a net saving of $31 ($46 - $15). In addition, the preference has reduced the firm's regular tax by $46, thereby reducing the deduction from minimum taxable income--that is, minimum taxable income goes up by $46 because of the preference. This increment is also taxed at 15 percent, so that the total additional tax is $21.90 ($15.00 + $6.90). Thus, the resulting value of the tax preference is $24.10 ($46.00 - $21.90), and the effective minimum tax rate is 21.9 percent.

The standard tax rates specified by the law are 70 percent (of the windfall profit)[5] on tier one oil, 50 percent on tier two oil, and 30 percent on tier three oil.[6] For oil in either tier one or tier two, the act specified reduced rates for independent oil producers on their first 1,000 barrels of production per day.[7] The reduced rate on tier one oil is 50 percent and on tier two 30 percent; there is no reduced rate on tier three oil. Royalty holders are not eligible for the reduced tax rates. Table 5 sets out the tax rates and production shares for 1981 in each category of oil.

In 1981, 6.5 percent of tier one oil (4.5 percent of all taxable oil) was subject to the lower 50 percent rate for independents. This advantage was equivalent to about $3 per barrel of production. On 1,000 barrels per day of production, this amounted to about $1.1 million per producer on an annual basis. This benefit, however, should decline as long as oil prices remain steady (or increase less than the rate of inflation). Because the windfall profit declines if oil prices rise less than the GNP deflator, the tax differential is smaller when real oil prices are lower. In 1981, tier one oil was approximately 70 percent of domestic production. The total tax advantage for reduced rates (on tier one oil) in that year was roughly $494 million. Because the tax is deductible against the corporate income tax, however, the net benefit is only about $266 million since the lower rate reduces the amount allowable as a deduction, thereby increasing income taxes.[8]

<u>Stripper Exemption</u>. Tier two oil (about 14 percent of domestic production) was also subject to reduced rates for independent producers

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5 The windfall profit is defined as the difference between the market wellhead price and the 1979 controlled price. For example, the tax on tier one oil equals 70 percent of the market price less the base price; that is, tax = 0.7 (market price - base price). The controlled (or base) price is indexed to reflect changes in the GNP deflator.

6 The tax rate on newly discovered oil was reduced by the Economic Recovery Tax Act of 1981 to 15 percent over a six-year period. The current rate is 25 percent and will be 15 percent starting in 1986.

7 As defined by the Windfall Profits Tax Act of 1980, an independent's status is determined on a quarterly basis instead of on an annual basis. Thus, in any quarter an independent cannot refine more than 50,000 barrels on any day nor have retail sales in excess of $1.25 million.

8 This assumes a marginal tax rate of 46 percent for both individuals and corporations.

TABLE 5 SHARES OF TAXABLE PRODUCTION AND WINDFALL PROFIT TAX LIABILITY BY OIL TIER (1981)[a]

Oil Tier	Percent of Taxable Oil Production	Percent of Windfall Profits Tax Liability
Tier One	70.3	82.0
Taxed at 70%	65.8	77.3
Taxed at 50%	4.5	4.6
Tier Two	13.1	11.2
Taxed at 60%	8.3	8.6
Taxed at 30%[b]	4.8	2.6
Tier Three (Taxed at 30%)	16.6	6.8
Newly discovered[c]	11.3	5.2
Incremental tertiary	0.6	0.3
Heavy oil	4.6	1.3
Total	100.0	100.0

SOURCE: U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 2 (Fall 1982), p. 44.

a. Taxable production excludes production that is exempt, such as state and local government interests, Indian oil, or charitable interests.

b. Production in this class is basically stripper production, which has been made exempt from tax as of January 1, 1983.

c. The newly discovered tax rate is now 25 percent and will decline to 15 percent in 1986 and thereafter.

under the 1980 act. This advantage has been superseded, however, because the Economic Recovery Tax Act of 1981 (ERTA) basically exempted all stripper production by independent companies. In the first quarter of 1982, the average tax per barrel of tier two oil (produced by an integrated company) was $7.80.[9] Because the independent tax rate was half the normal rate, the tax benefit was about $3.90. With the adoption of the stripper exemption, this advantage is now equivalent to the full $7.80. Because the tax is deductible against the income tax the net advantage is about 54 percent of this amount. In addition, the decline in oil prices has also eroded this tax advantage. It is estimated that the current tax differential for independents on stripper oil is now about $6.10 (gross) per barrel (assuming a $30 barrel of oil).

The exemption for stripper oil does not count against a firm's 1,000 barrel limit on oil eligible for reduced rates in either tier one or tier two. (Independents could have some tier two production resulting from the Naval Petroleum Reserve.) A firm could, for example, exempt 700 barrels per day of stripper oil and still receive favorable tax treatment on 1,000 barrels per day of tier one and/or tier two oil.

The exemption of stripper oil was justified in order to prevent "premature abandonment of such properties as the costs of production rise relative to the income available from the property."[10] This exemption will have the effect of extending the economic life (and increasing the ultimate total production) of oil wells that are marginally profitable. That this exemption was only allowed independent producers seems inconsistent with the general intent of the law, however. In 1981, about 40 percent of the output from stripper leases was produced by the top 24 companies (on a net company basis). This indicates that stripper oil production is not solely a province of the independent firm. From the policy standpoint of increasing oil production, there does not appear to be any rationale for eliminating an incentive for independents to cap wells while retaining it for integrated firms.

WINDFALL TAX EXEMPTION FOR ROYALTY HOLDERS

Current law allows royalty holders an exemption from the windfall profit tax of two barrels of production per day in 1982 through 1984; in

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9 U.S. Department of the Treasury, Internal Revenue Service, Statistics of Income Bulletin, vol. 2, no. 3 (Winter 1982-83), p. 42.

10 Joint Committee on Taxation, General Explanation of the Economic Recovery Tax Act of 1981, p. 321.

1985 and thereafter, the exemption will be three barrels per day. When originally passed, the Windfall Profit Tax Act did not include any tax exemption or credit for royalty holders. However, the Omnibus Reconciliation Act of 1980 established a $1,000 tax credit for royalty holders on oil removed in 1980; no provision was made for subsequent years. In ERTA, the Congress extended this credit to $2,500 for 1981 and provided the exemptions that exist under current law for 1982 and thereafter. The rationale for this credit was that the "windfall profit tax on small amounts of royalty income imposed a hardship on many low- and middle-income taxpayers."[11] In 1983, the average tax per barrel is estimated to be about $4.50 (gross) and $2.25 (net), assuming a price of $30.[12] Thus, the two-barrel-per-day exemption currently in effect is equivalent to about a $1,640 credit for the taxpayer facing a 50 percent marginal tax rate, which is less than the $2,500 credit allowed in 1981. (For the taxpayer in the 30 percent tax bracket, the equivalent credit is $2,300.) If the three-barrel-per-day exemption were effective in 1983, it would result in an equivalent credit of about $2,460 for the taxpayer in the 50 percent bracket, and $3,450 for the taxpayer in the 30 percent bracket.

Although the exemption helps low- to moderate-income royalty holders, it also provides a tax break for the high-income taxpayer. In 1980, 57 percent of the net royalty income (from all sources, not only from oil and gas) was reported on returns filed by taxpayers with an adjusted gross income (AGI) in excess of $50,000.[13] Twenty percent of the returns reporting any royalty income had adjusted gross incomes in excess of $50,000. The two-barrel-per-day exemption implies that the royalty holder may be receiving (gross) royalty income of $21,900 annually (at a $30.00 price per barrel) free from the windfall profit tax. The three-barrel-per-day exemption results in $32,850 tax-free royalty income. (Although these royalties are exempt from the windfall profit tax, they remain subject to the regular personal income tax.) For reference, the average AGI on tax returns in 1980 was about $16,200; the average royalty income (from all sources) for royalty recipients with AGI under $50,000 was $3,184; and for royalty recipients with AGI over $50,000 it was $17,293.

In 1982, about 4 to 5 percent of domestic oil production was subject to the royalty exemption. For the calendar year, the tax saving was

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11 Ibid.,

12 The net is lower than the gross because the windfall profits tax is deductible against the personal income tax.

13 Net royalty income is gross royalties <u>less</u> depletion and other related costs.

approximately \$856 million (gross); on a net basis the saving was about \$498 million. The net saving is less than the gross because lower windfall profit taxes results in a lower deduction (for taxes) and higher personal income taxes.

INTANGIBLE DRILLING COSTS

Until the Tax Equity and Fiscal Responsibility Act of 1981 (TEFRA), both independent and integrated oil producers were allowed to expense their expenditures for intangible drilling costs. These are capital expenditures with no salvage value, such as amounts paid for fuel, labor, materials, and supplies used in the preparation and drilling of oil or gas wells. They exclude expenditures for lease equipment, such as storage tanks or pumping machinery, which would be handled as five-year recovery property under ACRS. Although lease equipment is eligible for the investment tax credit, intangible drilling costs (IDCs) that are expensed do not qualify for the credit. The combination of accelerated depreciation and the investment tax credit is about equivalent to expensing at a 10 percent discount rate; thus, lease equipment and expensed IDCs currently receive similar effective tax treatment.

In TEFRA, the Congress reduced (to 85 percent) the percentage of IDCs that integrated oil corporations could expense; the independent companies may still deduct 100 percent of their IDCs. The remaining 15 percent of an integrated firm's IDCs are amortized on a straight-line basis over three years. In present value terms, this provision reduced the value of deduction for IDCs from 100 percent to about 97 percent (using a discount rate of 10 percent). This provision only applies to producing properties--intangible costs associated with dry holes will continue to receive full expensing treatment.

Minimum Tax Considerations. While the TEFRA provisions directly scaled back the deductions for IDCs for integrated firms, the minimum tax on individuals reduces the value of these deductions for limited partnerships and Subchapter S corporations. Before TEFRA, the individual minimum tax (and the corporate minimum tax for Subchapter S firms) required individuals to include intangible drilling costs in their minimum tax base.[14] The minimum tax rate was 15 percent, and 10 percent of the

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14 Intangible drilling costs are included in a taxpayer's minimum tax base to the extent that (1) they exceed the amount that would have been deducted had they been amortized over ten years; and (2) that the amount in (1) is greater than a taxpayer's net income from oil and gas properties.

IDC was deductible in the first year. Thus, the minimum tax imposed an effective tax rate of 13.5 percent on the preference, assuming the taxpayer was subject to the tax.[15] For a taxpayer in the 50 percent tax bracket, this provision was equivalent to reducing the preference by 34 percent, to 66 percent of its original value.[16]

Under TEFRA, individuals in partnerships, sole proprietorships, or Subchapter S corporations are subject to a new alternative minimum tax which replaces the minimum tax under prior law. The new minimum tax includes IDCs as a tax preference and the deduction is taxed at a marginal rate of 20 percent (instead of 15 percent as under previous law). The amount of IDCs included in the alternative minimum tax base equals the amount in excess of straight-line amortization over ten years. This is the same definition as under pre-TEFRA law. The alternative minimum tax on IDCs has the same kind of effect as it does on percentage depletion. The marginal IDC deduction ($100) changes from a $50 tax saving under the regular tax (for the taxpayer in the 50 percent bracket) to an $18 liability under the alternative tax. Thus, extra IDC deductions for persons subject to the alternative minimum tax are worthless.[17]

Individuals with limited partnership interests have the option of amortizing their IDCs over ten years (straight-line), and thereby excluding them from the minimum tax base. Taxpayers will find it to their advantage to use the option to capitalize their IDCs if they are subject to the alternative minimum tax. For example, the taxpayer in the 50 percent bracket would reduce the present value of the tax deduction from $50 to

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15 Under pre-TEFRA law 50 percent of a taxpayer's regular tax was deductible against the taxpayer's minimum taxable income. Thus, the direct minimum tax on IDCs would be $13.50 (per $100 of deduction) and the indirect tax would be $3.75 for a total of $17.25. The indirect tax equals 15 percent of one-half of the reduced liability resulting from the preference. In the case of the taxpayer in the 50 percent bracket, $3.75 = (0.15)(0.5)(0.5)($100).

16 The taxpayer could have capitalized intangible drilling costs and recovered them through cost depletion, thereby avoiding the minimum tax. However, this was probably not a profitable strategy since future deductions are worth considerably less than current deductions (on a present value basis).

17 This assumes that the full amount of the "excess" IDCs are included in the minimum tax base. To the extent that income from other oil and gas properties is used to reduce the excess IDCs, the reduction in the value of the preference will be less.

$32.25 by amortizing it over ten years (assuming a 10 percent discount rate). This reduction, however, is clearly preferable to the alternative of an $18 liability to the IRS.

TEFRA also included a second option for taxpayers who are operators (for example, general partners or sole proprietors) of oil and gas properties. These individuals are permitted to treat IDCs as five-year recovery property under ACRS, and thereby exclude IDCs from their minimum tax base. Under ACRS, the taxpayer is entitled to accelerated depreciation plus the 10 percent investment credit (subject to the 50 percent basis adjustment). At a 10 percent discount rate, this option for IDCs is about equivalent to expensing; at a lower discount rate, it is more generous than expensing. Thus, the alternative minimum tax can be completely escaped (at no cost) by taxpayers who are operators of oil and gas properties. Because the ACRS option was not available under prior law, TEFRA actually reduced the minimum tax burden on taxpayers with an active interest in oil and/or gas production.

The current treatment of IDCs for different types of taxpayers is summarized in Table 6.

AT-RISK RULES

The Tax Reform Act of 1976 placed a limitation on the tax loss associated with an oil and/or gas investment that a taxpayer could deduct; the tax loss cannot exceed the amount the partner is personally liable for. This provision was necessitated by the prevalence of limited partnerships where the partners' personal liabilities are limited to their capital contributions. For example, a partnership may incur a debt for which the partners are not personally liable if the loan cannot be repaid. To the extent that loans were used to drill wells, the intangible drilling costs allocated to the partners could thus have exceeded their capital investment. Limited partners were thereby able to leverage their investment, without facing the concommitant personal liability should the project fail. Under the 1976 tax rules partnerships can still borrow, but the tax losses allowed cannot exceed the capital interest of the partners, unless they are personally liable for these loans. Corporations that invest in limited partnerships are subject to the same at-risk rules as individuals.

In general, sole proprietorships and general partnerships are liable for the full amount of debt they incur, and are allowed to write off the full amount of any tax loss related to their investments. Corporations (both regular and Subchapter S) allow stockholders to limit their personal liability to their capital investment. Corporate stockholders in regular (non-Subchapter S) corporations cannot deduct any more than their capital

TABLE 6. TAX TREATMENT OF INTANGIBLE DRILLING COSTS

Type of Taxpayer	Tax Treatment	Present Value of $100 Deduction[a] (dollars)	Present Value of Tax Saving (dollars)
Corporation - Integrated (46 percent tax rate)	First-year expensing of 85 percent of IDCs; the remainder amortized over 3 years (straight-line)	97.40	44.80
Corporation - Independent (46 percent tax rate)	First-year expensing	100.00	46.00
Sole proprietor or general partnership (50 percent tax bracket and subject to alternative minimum tax)	Either (A) First-year expensing subject to minimum tax rules **or**	-90.00[b]	-18.00
	(B) Treat IDCs as five-year recovery property; no minimum tax	98.50	49.25
Limited partner (50 percent tax bracket and subject to alternative minimum tax)	Either (A) First-year expensing subject to minimum tax rules **or**	-90.00[b]	-18.00
	(B) Amortize IDCs over 10 years; no minimum tax	64.50	32.25
Individual (50 percent tax bracket and <u>not</u> subject to alternative minimum tax)	First-year expensing	100.00	50.00

a. Assumes a 10 percent discount rate and $100 IDC.

b. Assumes taxpayers have no net income from oil and gas properties; the excess IDCs equal the difference between expensing and ten-year amortization. The negative sign implies that there is <u>no</u> tax saving, but an actual tax liability.

investment as a tax loss--this would happen if the corporation's stock price dropped to zero. The corporation structure, even though it provides limited liability to its shareholders, does not allow any tax losses to flow through to stockholders that are in excess of their investment. In contrast, Subchapter S firms both provide limited liability to their shareholders and allow tax losses to "flow through" to the owners, much as under a limited partnership. (The Subchapter S Revision Act of 1982 eliminated the limitations on the extent to which shareholders could utilize percentage depletion deductions.) The Subchapter S rules, however, limit the tax loss that can be claimed by the taxpayers to their capital basis plus any indebtedness of the corporation to the stockholder. Thus, for purposes of the at-risk rules, Subchapter S firms are treated analogously to limited partnerships.

In general, the tax law prevents <u>all</u> individuals from generating tax losses in excess of their capital investment, unless they are personally liable for the debts incurred to generate those losses.

<u>ACCELERATED WINDFALL PROFITS TAX PAYMENTS</u>

In general, the first purchaser of domestic crude is required to withhold the windfall profit tax amounts payable to the producer and deposit those amounts with the Treasury. The purchaser is liable to the Internal Revenue Service (IRS) for the payment of the amount withheld, as determined by the certification provided by the operator. (This includes any certification of any part of the production eligible for reduced independent tax rates or exemption.) The purchaser files a quarterly return showing the tax withheld and provides each producer with an information statement indicating the amounts of oil purchased and the tax withheld.

The first purchaser must deposit the withheld payments to the IRS within a certain length of time. Major refiners or retailers are required to make semi-monthly estimated deposits of withholding tax. All other purchasers are required to make deposits within 45 days after the end of the month in which the oil was removed from the premises.[18]

The interval between when a tax is withheld and when it is deposited allows a firm to earn interest on the withheld amounts for that interval. On average, the majors are allowed a very brief period (7.5 days) between the time when a tax is withheld and it is due the Treasury. (This assumes

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18 These provisions are described in Joint Committee on Taxation, <u>General Explanation of the Crude Oil Windfall Profit Tax Act of 1980</u>, pp. 57-58.

that tax is withheld at a constant daily rate over the month.) In contrast the independent purchaser is allowed 60 days (on average) before the withheld tax must be deposited. Thus, on average, the independent purchaser may be able to earn eight times more interest on the withheld tax collections than a major company could. To the extent that the independent operator takes on the deposit obligations of an independent first purchaser, the operator can take advantage of the delayed timing of the liability (the operator and the first purchaser may elect to have the operator assume the purchaser's responsibilities under the tax, Code § 4995(a)(7)(A).) However, if the first purchaser is a major company, the independent operator's payment obligation is the same as for a major company.

REVENUE PROJECTIONS

Significant revenues could be raised over the 1984-1988 period by making the tax provisions consistent for all firms. Table 7 sets forth CBO's revenue projections from various changes in the tax law that would move toward uniformity of treatment for different producers.

Two options are presented for intangible drilling costs. The first option--capitalization of all intangible drilling costs associated with producing wells--would apply to both independents and integrated companies. This would require firms to amortize their drilling costs over the productive life of the well, rather than expensing them all (or 85 percent) in the first year. These costs would be added to the depletable basis of the property and recovered through cost depletion. Currently, this is the generally accepted practice that firms use for financial (as opposed to tax) reporting. The second intangible drilling cost option would only affect independent companies--it would require them to amortize 15 percent of their IDCs over three years as is currently required of integrated companies.

There are also two options for the windfall profit tax. The first would eliminate the current independent exemption for stripper oil, but would leave intact the reduced rate of 30 percent. The second alternative is more sweeping in that both the stripper exemption <u>and</u> the reduced rates on both tier one and tier two oil would be abolished. Under this option, all tier one oil would be taxed at a 70 percent rate and <u>all</u> tier two oil would be taxed at 60 percent. (Interests currently exempt, such as state and local governments, Indian oil, or charitable oil would remain untaxed.) Both these options would only affect production by the independent companies.

The option to repeal percentage depletion would also only affect the independent firms. Under this alternative, firms would be required to use

TABLE 7. ESTIMATED REVENUE EFFECTS OF CHANGING TAX PROVISIONS FOR OIL AND GAS PRODUCERS (By fiscal year, in billions of dollars)

Option	1984	1985	1986	1987	1988	Cumulative Five-Year Increase
Capitalize All IDCs	2.1	3.6	3.3	3.2	3.1	15.3
Amortize 15 Percent of IDCs over 3 Years	0.1	0.1	0.1	*	*	0.4
Eliminate Stripper Exemption for Windfall Profits Tax (Retain Reduced Tax Rate)	0.2	0.2	0.2	0.2	0.2	1.1
Eliminate All Reduced Windfall Profit Tax Rates for Independents (No Stripper Exemption)	0.5	0.6	0.5	0.5	0.5	2.6
Repeal Percentage Depletion	0.9	1.7	1.9	2.0	2.2	8.7
Repeal Exemption for Royalty Holders	0.4	0.5	0.4	0.4	0.4	2.0
Expense All IDCs	-0.2	-0.2	-0.1	-0.1	-0.1	-0.6
Extend Stripper Exemption to Include All Producers	-0.7	-0.9	-0.9	-0.9	-0.9	-4.3

SOURCES: Joint Committee on Taxation and Congressional Budget Office.

* Less than $50 million.

the cost depletion methods that the integrated companies are currently required to use. In general, the independent companies already use cost depletion for financial reporting purposes so that they can report higher earnings to their shareholders.

Repeal of the two-barrel-per-day exemption from the windfall profit tax for royalty holders would not directly affect either the independent or the integrated producers, as the exemption does not distinguish oil by type of producer. Instead, it would make the tax treatment of holders of nonoperating royalty interests the same as that of operating interests, who are not currently allowed the exemption. Elimination of the exemption would primarily affect those individuals who are currently royalty recipients.

Lastly, two options are included that would increase consistency, but would reduce revenues. The first option would repeal the 15 percent reduction of the first-year write-off for drilling costs adopted in TEFRA. All firms would be allowed full expensing. The second alternative would extend the stripper exemption to integrated as well as independent firms. Thus, the windfall profit tax would not impose an incentive for any firm to abandon wells that might still be economically productive.

PART III. METHODOLOGY FOR ESTIMATING PRODUCER TAX BURDENS

One approach to measuring the overall burden of taxation on oil and gas production is to estimate the total taxes a producer is liable to pay over the life of a given property. By discounting the tax payments back to the present, the total "present value" of tax payments can be calculated. This method allows all tax provisions and their timing differences to be taken into account.

The basic framework for this approach involves a "discounted cash-flow" (DCF) model that forecasts the revenues and costs from an oil investment over its life. The investor (producer) discounts the investment's income stream over time in order to calculate the total present value of future income from the project. The investor will purchase the property as long as the owner's asking price is less than or equal to the estimated value of the future net income stream. In the DCF model used here, it is assumed that the investor is willing to pay the landowner an amount (the lease bonus) that is exactly equal to the present value of the future net cash flow.

The discount factor used in the model is 12.5 percent and reflects the minimum anticipated return that the investor will accept after all taxes. If the after-tax return is less than 12.5 percent, the investor will forgo the investment opportunity. Thus, the investor will offer the landowner a bonus that assumes a 12.5 percent post-tax return over the life of the investment.

The DCF model is used to estimate the taxes of three different organizations as follows:

1. Major Integrated Corporation. The investor in a major corporation pays the corporate income tax, the personal tax on dividends, and the capital gains tax on retained earnings. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The major firm must pay full windfall profits tax rates and must use cost depletion. (The cost depletion basis equals the upfront bonus payment for the property.) Eighty-five percent of intangible drilling costs are written off in the first year, the remainder are amortized over three years.

2. Independent Corporation. Like the investor in the integrated firm, the individual who invests in an independent firm pays the corporate income tax, the personal income tax, and the tax on capital gains. It is assumed that the firm distributes 40 percent of its cash flow and retains 60 percent. The independent corporation pays lower windfall profits rates and is allowed percentage depletion on 1,000 barrels per day of oil production. Because the firm is allowed percentage depletion, it must also pay the add-on minimum tax equal to 15 percent of the excess of percentage depletion over the adjusted cost basis of the property. The firm is allowed to expense all intangible drilling costs.

3. Sole Proprietorship or Partnership. This firm is composed of an individual operator or group of operators (who are not corporations) that all have working interests in the property. This type of organization is advantageous because it avoids the corporate income tax altogether; the individual(s) are subject only to the personal income tax. The firm is allowed reduced windfall profits tax rates, and percentage depletion on the first 1,000 barrels per day of oil production. It is assumed that the owners are not subject to the alternative minimum tax on either percentage depletion or intangible drilling.

In order to provide consistency, it is assumed that the investors in all three firms are in the same tax bracket (50 percent). In addition, it is assumed that all individuals and firms have sufficient taxable income to absorb all the deductions that might arise from an oil investment property. For capital gains purposes, it is assumed that the shareholders hold their stock for four years and then realize their gains. The effective capital gains tax rate under this assumption is 15 percent (instead of the statutory 20 percent), and the overall effective personal tax rate (as a percentage of current cash flow) is 29 percent. In other words, the personal income tax rate is 29 percent for investors in a corporation and 50 percent for investors in a noncorporate enterprise. It is assumed that none of the properties are sold during their productive lives.

The three hypothetical properties differ in their production profiles and investment characteristics. Table 8 presents the variables for each property. For simplicity, it is assumed that the future price of oil increases at the same annual rate as inflation (5 percent). The wells were chosen so that the production from each well would be treated differently for purposes of the windfall profits tax. Well No. 1 is assumed to produce "new" oil, Well No. 2 is basically a stripper well, and Well No. 3 produces "old" oil.

TABLE 8. ASSUMED VARIABLES FOR DCF MODEL

	Well No. 1	Well No. 2	Well No. 3
Required Post-Tax Rate of Return (Hurdle Rate)	12.5 percent	12.5 percent	12.5 percent
Time of Investment	1983:1	1983:1	1983:1
Time of Initial Production	1983:2	1983:2	1983:2
Time of Peak Production	1984:2	1984:1	1984:2
Time Production Starts to Decline	1985:1	1985:1	1986:1
Peak Production Rate (barrels per day)	200	15	50
Initial Reserves	487,539	50,622	121,262
Production Decline Rate	15 percent	10 percent	17.5 percent
Annual Operating Cost	a/	a/	a/
Drilling Investment (producing well)	\$ 750,000	\$ 250,000	\$ 400,000
Drilling Investment (dry wells)	\$ 2,100,000	0	\$ 300,000
Lease Equipment Investment	\$ 160,000	\$ 40,000	\$ 60,000
Oil Tier	Tier 3	Tier 1-2	Tier 1
Windfall Profits Base Price	\$ 23.45	\$ 19.84	\$ 16.11
Oil Price Inflation	5 percent	5 percent	5 percent
GNP Price Inflation	5 percent	5 percent	5 percent
Royalty Rate -- to Landowner	12.5 percent	12.5 percent	12.5 percent
State Severance Tax Rate	4.6 percent	4.6 percent	4.6 percent

a. Annual operating cost equals \$8,000 plus \$60 per barrel of daily production. This amount is adjusted by the GNP price index over time.

The way the DCF model is structured allows the bonus payment to vary to reflect differences in tax treatment. The full amounts of any differences in taxation are assumed to be 100 percent capitalized into the lease bonus. This implies that taxation does not affect oil prices, but that it is manifested in lower payments to the landowners. Thus, higher taxes would mean that the landowners would be paid less, and vice versa.

The DCF model measures only the returns from prospective investments; it does not indicate the returns to past investments. Once the investment becomes a sunk cost, the actual taxes paid over its life will be a function of actual events, not of forecasts or assumptions. In terms of affecting investment behavior on the margin, it is the prospective post-tax returns that determine a firm's investment decisions. The oil production profile used in the DCF model is the expected profile prior to the investment. Ex post evaluations may significantly differ as more information is gained. However, ex post evaluations do not determine initial investment decisions, although they do affect subsequent marginal decisions concerning recovery techniques.

The results from the DCF model are summarized in Table 9. The taxes and tax rates are higher for the corporations than for noncorporate firms because of the corporate income tax. The rates shown here are higher than might be expected, but this analysis is limited to investors in the 50 percent personal tax bracket.

The first well provides an interesting contrast between the integrated and independent corporations. Because it is classified as new oil (tier three), both firms pay the same amount in windfall profit taxes. The integrated firm pays about 20 percent more in corporate taxes because of the requirement for cost depletion and the amortization of 15 percent of its IDCs. This is partially offset because the independent must pay the add-on minimum tax for percentage depletion. In addition, the investors in the independent must pay higher personal taxes because the firm's after-tax cash flow is higher. As a result of these offsetting effects, the overall taxation of the independent is about 5 percent (three percentage points) less than for the integrated company.

The difference in tax rates between the independent corporation and the general partnership indicates the advantage of organizing a firm on a partnership (or Subchapter S) basis. Both firms pay the same windfall profits taxes, but the partnership pays no corporate income tax. As a result, the partnership tax rate is about 20 percentage points lower for all three wells.

The DCF model can be applied to other properties under alternative assumptions. It is not likely, however, that these changes would alter the

TABLE 9. ESTIMATED PRESENT VALUE OF TAXES FOR THREE OIL WELLS (In thousands of dollars, except as noted)

Producer	Well No. 1	Well No. 2	Well No. 3
Integrated Corporation			
Corporate income tax	2,125.3	127.8	335.5
Add-on minimum tax	0	0	0
Windfall profits tax	200.9	140.7	602.5
Personal income tax	1,695.0	122.2	323.9
Total taxes	4,021.3	390.7	1,251.8
Tax per barrel (dollars)	8.25	7.71	10.40
Tax rate[a]	56 percent	61 percent	67 percent
Present value of tax depletion	534.2	3.8	16.3
Original depletion basis (lease bonus)	1,139.9	9.2	32.9
Independent Corporation			
Corporate income tax	1,760.4	98.1	261.9
Add-on minimum tax	64.1	11.3	30.2
Windfall profits tax	200.9	79.9	430.3
Personal income tax	1,782.3	145.2	386.4
Total taxes	3,808.7	334.4	1,108.8
Tax per barrel (dollars)	7.81	6.61	9.14
Tax rate[a]	53 percent	53 percent	61 percent
Present value of tax depletion	1,313.1	124.5	340.7
Original depletion basis (lease bonus)	1,353.5	65.4	185.9
Sole Proprietorship or Partnership			
Corporate income tax	0	0	0
Add-on minimum tax	0	0	0
Windfall profits tax	200.9	79.9	430.3
Personal income tax	1,802.6	106.9	285.1
Total taxes	2,003.5	186.8	715.4
Tax per barrel (dollars)	4.10	3.69	5.90
Tax rate[a]	31 percent	33 percent	44 percent
Present value of tax depletion	1,537.5	124.5	340.7
Original depletion basis (lease bonus)	3,157.7	213.1	579.3

a. The tax rate is the comprehensive marginal tax rate based on a corporate rate of 46 percent and a personal rate of 50 percent. The tax rate is the percentage difference between the pretax and post-tax rate of return on the total investment.

conclusion that the combination of preferential tax provisions significantly reduces the burden placed on independent oil companies--especially those that are organized on a noncorporate basis.